OIL AND GAS COMMISSION

Summary of Oil and Gas Activities and Results in British Columbia as of December 31, 2003

November 30, 2004

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Highlights

Industry

British Columbia continued to attract high levels of industry activity during the 2003 calendar year. Some of the noteworthy points were:

- Encana and Burlington appear posed to lead the development of the Cadomin formation in the Kelly-Cutbank area. The Cadomin formation in the area is seen as having the potential to be a very significant resource play. The application of the resource play strategy is expected to permit economic development of the extensive but relatively tight formation.
- Development of the Jean Marie play in the Gunnell Creek and Helmet areas continued to be the focus of much activity as industry more effectively defined drilling targets and optimized development efforts. The use of horizontal well technology to develop the Jean Marie has become the established norm for this resource play.
- Industry attained the province's highest-ever level of drilling activity with 770 gas wells and 69 oil wells having been drilled and completed.
- Raw natural gas production for the year totalled 30.8 billion cubic metres. This figure representing a 5% decrease from the 2002 record level, reflects the passing of the Ladyfern 'bubble' and a return to more sustainable production levels.
- Industry activity resulted in raw natural gas reserve additions that replaced 148% of production.
- Direct revenue to the province from industry activities totalled $2.11 billion, including royalties, tenure fees, and disposition bonuses. This revenue figure, representing a 70% increase over 2003's revenue, was by far the highest provincial oil and gas revenue in the province's history. Revenue for the 2001 calendar year was the next highest at $1.73 billion.

Oil and Gas Commission

The Oil and Gas Commission (Commission) continued to pursue its vision, "To be the innovative regulatory leader, respected by stakeholders, First Nations and clients" by undertaking initiatives on a number of fronts:

- Participated in developing amendments to the *Oil and Gas Commission Act* that have changed the governance of the Commission.

  The Commission now reports to its board, which

  - Manages the affairs of the Commission;
  - Provides guidance, approves the Commission's budget, service plans and regulatory initiatives; and
  - Establishes the Commission's organization.
- On June 24, 2003, the Lieutenant Governor in Council appointed Sheila Wynn, Deputy Minister of Energy and Mines, as Chair of the board. Derek Doyle, Oil and Gas Commissioner, was appointed Vice-Chair, and John Bechtold was appointed by the Lieutenant Governor in Council, as the third Director of the board, for a term of five years.

- Participated with the Ministry of Energy and Mines in the development of legislation amendments to the Petroleum and Natural Gas Act to accommodate new developments and facilitate oil and gas development by providing increased flexibility and reduced administration. The legislation amendments have been supported by corresponding revisions to the Geophysical Exploration Regulation, the Drilling and Production Regulation, the Petroleum and Natural Gas General Regulation, and Petroleum and Natural Gas Royalty and Freehold Production Regulation.
- Released the document *"OGC Guidelines for Application Submission, Besa-Prophet Pre-Tenure Plan, Phase 1"*. This guideline is intended to clarify operator application submission requirements in the Besa-Prophet Pre-Tenure Plan (BPPTP) area. The BPPTP was approved in August 2002. It is the first of a new series of pre-tenure plans being completed in the Muskwa-Kechika Management Area (MKMA). The application submission guide will also facilitate a common understanding of submission requirements between operator, the regulator, First Nations, and stakeholders.
- Implemented a number of changes in its organizational structure. These changes will accommodate the anticipated increase in oil and gas activities. The government's Oil and Gas Development Strategy, the First Nations' recommendation that we integrate the review of many projects into General Development Plans, and the stakeholder interest in enhanced compliance and enforcement clearly showed a need to fine tune the organization.

The Commission established three leadership roles to position itself for the challenges of the next five years:

- Leader of Operations and Deputy Commissioner;
- Leader of Relationships and Client Services; and
- Leader of Corporate Services.

The Leader of Operations has been charged with integrating the activities of the applications, compliance, drilling, engineering and reservoir management teams. The Leader of Operations acts for the Commissioner in his absence.

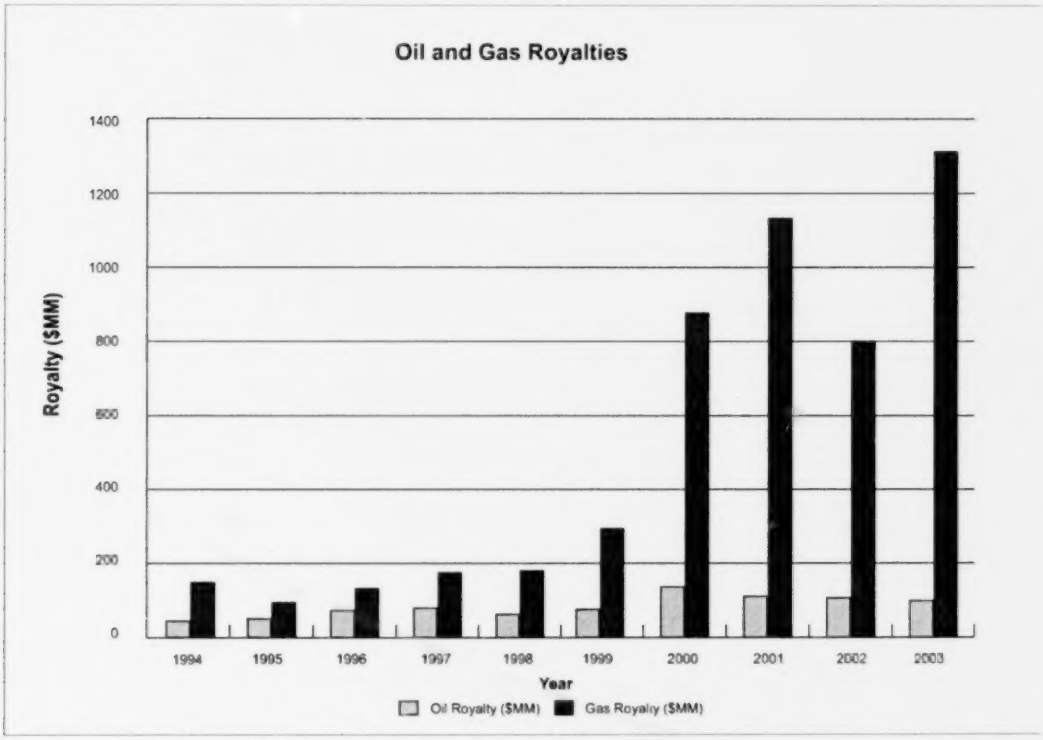
The Leader of Relationships and Client Services has been charged with moving the Commission's services to its clients toward performance and results based regulation. Included in this charge was the integration of the needs of communities, stakeholders and organizations into the Commission's daily duty, especially the strengthening of collaboration with First Nations.

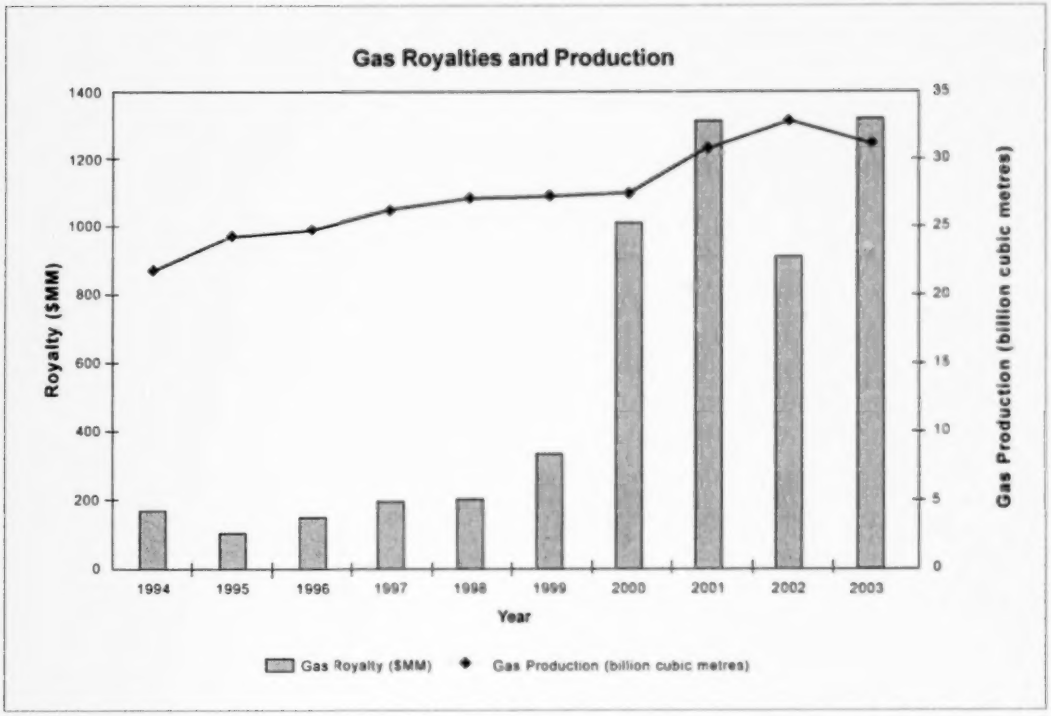
The Leader of Corporate Services has been charged with an increased focus on a performance management framework that establishes clear accountability for results. Included in this charge were the development and retention of human resources and the accelerated implementation of appropriate technology and information systems.

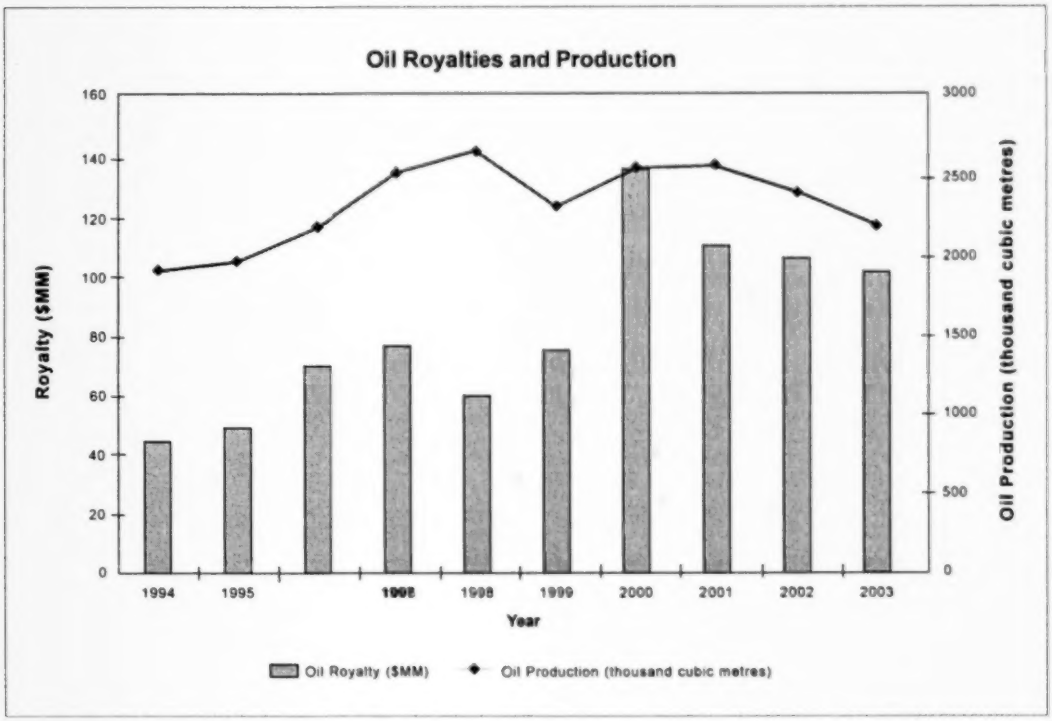
Activities

Petroleum and Natural Gas Royalties

Royalty revenue from oil, natural gas, and related by-products contributed $1.4 billion to the province's coffers. The vast majority, approximately 93%, of this revenue was realized from natural gas production. With gas production being at an all-time record high for the province and gas prices being strong, gas royalty revenue was the highest seen in the province's history.




Gas Royalties and Production
Royalty ($MM)
Gas Production (billion cubic metres)
Year
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
Gas Royalty ($MM)
Gas Production (billion cubic metres)

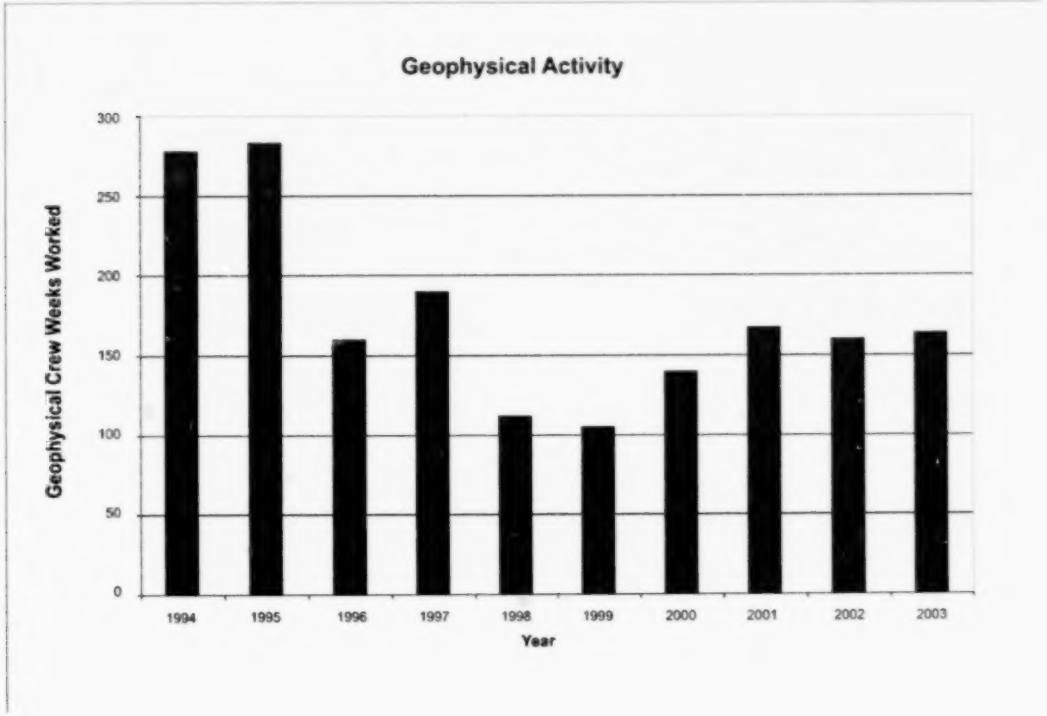

Oil Royalties and Production
Royalty ($MM)
Oil Production (thousand cubic metres)
Year
1994
1995
1998
1999
2000
2001
2002
2003
Oil Royalty ($MM)
Oil Production (thousand cubic metres)

The Ministry of Energy and Mines introduced a number of royalty incentive programs during the 2003 calendar year. As the Oil and Gas Commission does not administer these programs, no comments are offered here concerning any of those incentives. For information regarding the royalty incentive programs, interested readers are directed to the Ministry of Energy and Mines' website at *http://www.em.gov.bc.ca/subwebs/oilandgas/royalties/newtargeted.htm.*

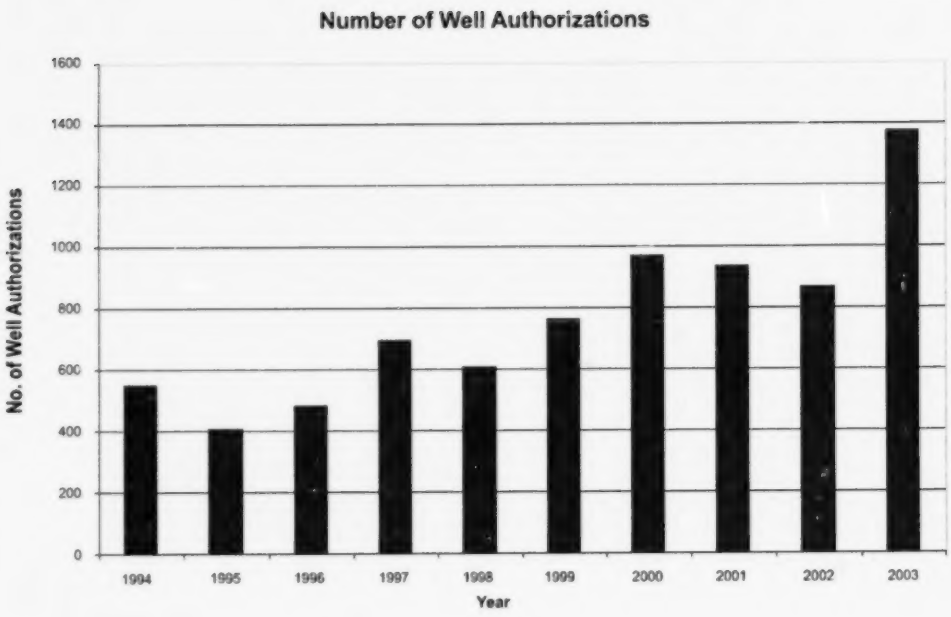
The Ministry of Energy and Mines, through its Titles Division, administers oil and gas tenure in the province. The oil and gas tenure process is an important aspect of industry activity that, as with the royalty programs, is not administered by the Oil and Gas Commission. For information regarding the oil and gas tenure process, interested readers are directed to the Ministry of Energy and Mines' website at *http://www.em.gov.bc.ca/subwebs/Landsale/main.htm.*

Geophysical

Geophysical activity remained high, increasing slightly compared to the 2002 level. The 2003 activity level of 164 crew-weeks was the highest activity level since 1997. Activity continues to shift to be more focused on 3-D seismic surveys. 3-D surveys are better able to identify the small pools that contain an increasing fraction of the remaining reserves in the Western Canadian Sedimentary Basin in British Columbia.



Well Authorizations



A total of 1376 well authorizations were issued during the 2003 calendar year. This represents the highest ever annual level of well authorizations issued in the province.

Of the 1376 well authorizations issued, 838, or 61%, were identified as being for development wells. Four hundred and eighty five, or 35%, were for exploratory outpost wells and 40, or 3%, were for exploratory wildcat wells. Eight wells were classified as experimental and five wells did not have a classification indicated in the records. The percentage of development wells appears to be returning to the values seen in the early 1990s when it was typically about 60%. The percentage of exploratory outpost wells has increased from about 30% in the early 1990s. The percentage of exploratory wildcat wells has decreased from about 7% in the early 1990s. The reduced percentage of exploratory wildcat wells may be a reflection of large number of development wells involved in the resource-play developments being undertaken.

The following table shows the top five operators. These rankings were determined by the number of well authorizations issued in 2003.

Operator	No. of Well Authorizations
Encana	440
Canadian Natural Resources Ltd.	200
Burlington Resources Canada Ltd.	123
Penn West Petroleum Ltd.	52
Devon Canada Corporation	50

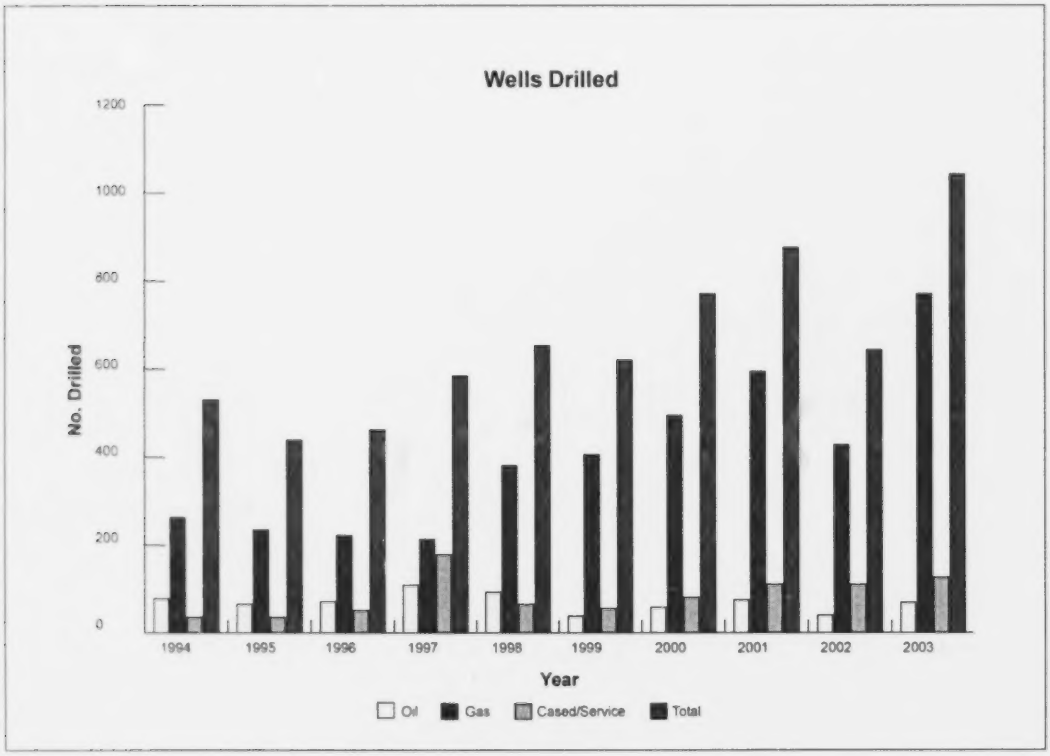
Combined, these five operators received well authorizations for 813 wells or 59%, of the total well authorizations issued during 2003.

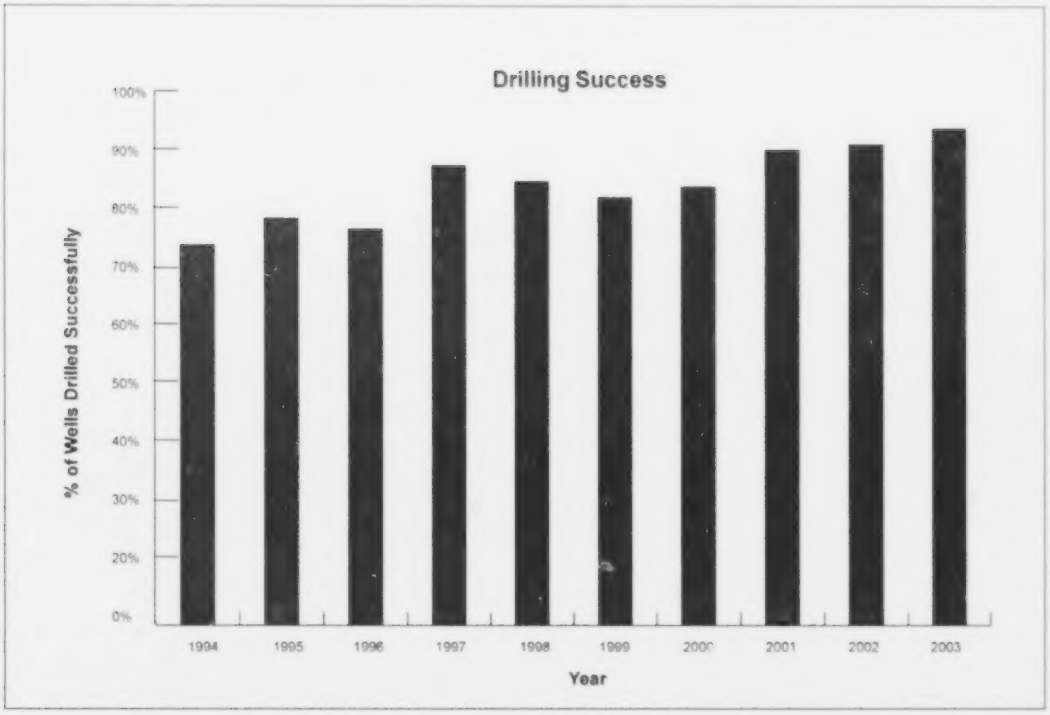
Wells Drilled

Drilling activity was the highest the province has ever seen. The majority of the wells drilled were completed as gas wells (770 gas wells out of a total of 1041 wells drilled). The large increase in gas wells drilled as compared to calendar 2002 is considered to be a result of both strong gas prices and the development of relatively tight reservoirs requiring increased drilling density.

Wells Drilled

Year	Oil	Gas	D&A	Cased/ Service	Total
1994	78	262	154	35	529
1995	65	234	104	35	438
1996	71	221	118	51	461
1997	109	213	83	178	583
1998	93	380	113	66	652
1999	38	405	121	56	620
2000	58	494	137	81	770
2001	75	594	95	111	875
2002	40	427	66	110	643
2003	69	770	76	126	1041

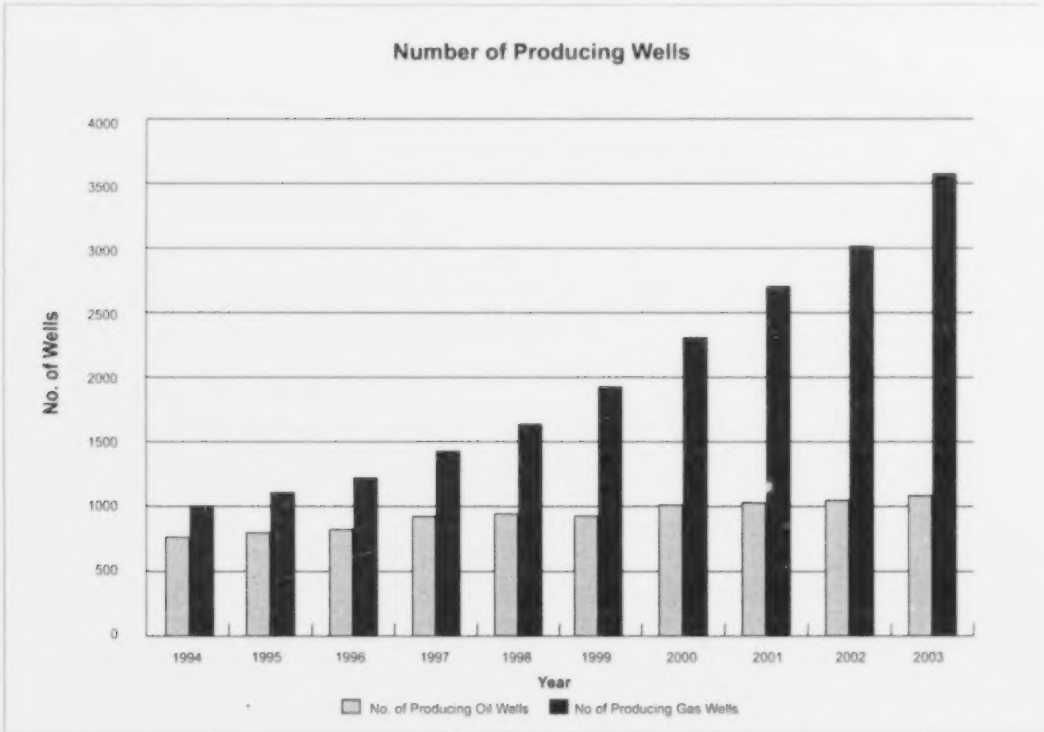




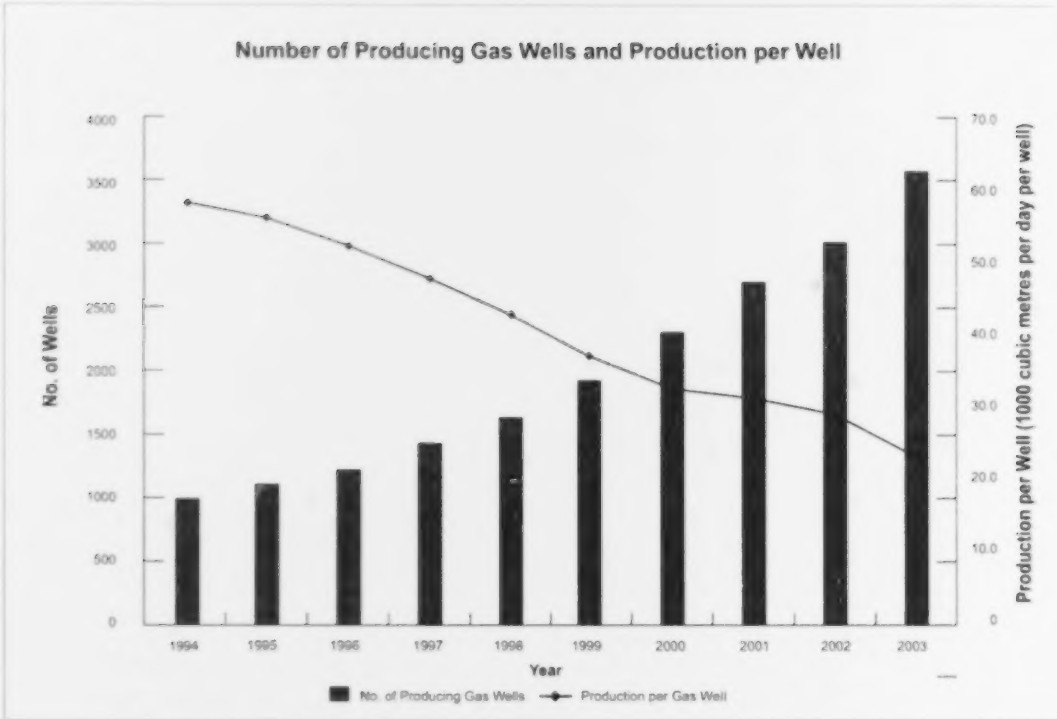
The new high in the percentage of wells drilled that were completed, is considered reflective of the high level of sophistication employed with respect, not only to drilling and completion technology, but also the more powerful exploration techniques being utilized.

Depth Drilled (1000 metres)

Year	Development	Exploratory Outpost	Exploratory Wildcat	Experimental	Total
1994	478	202	136		816
1995	342	175	139		656
1996	377	219	129	3	728
1997	505	295	128		928
1998	578	300	95		973
1999	539	311	74		924
2000	706	402	92	4	1204
2001	823	571	110	15	1519
2002	702	399	130	5	1236
2003	1162	686	158	16	2022



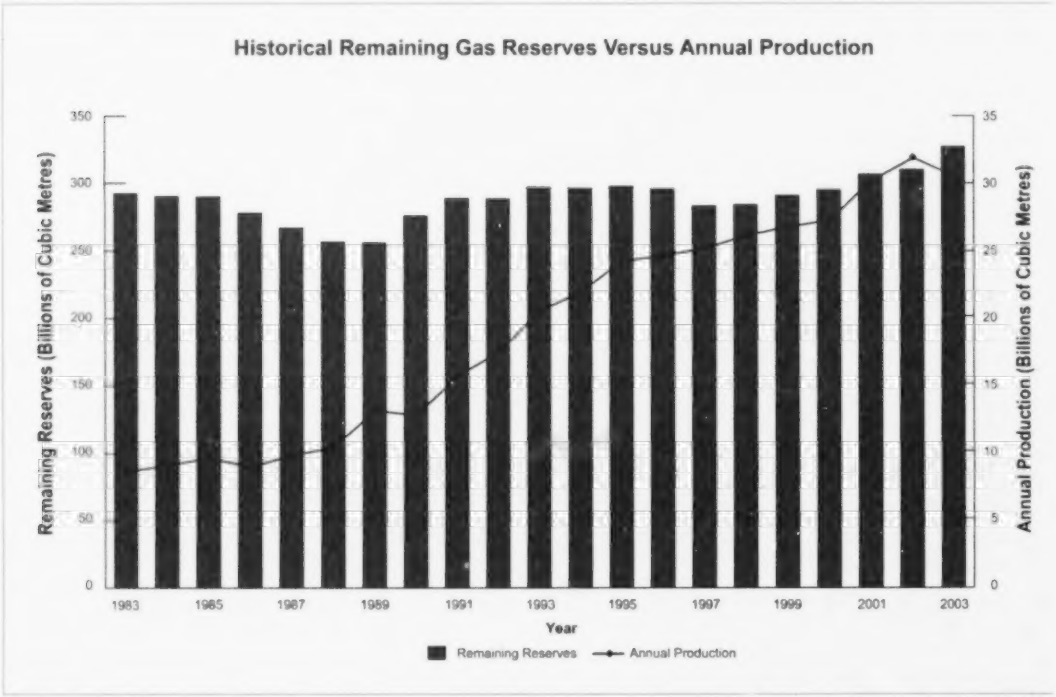
The number of producing wells increased significantly but the trend of decreasing deliverability per well continued. The decreasing productivity per well is seen as a reflection of the maturity of the Western Canadian Sedimentary Basin in British Columbia. The increasing pursuit of gas from relatively low permeability reservoirs suggests the decreasing well deliverability per well trend may be expected to exacerbate as overall gas production volumes increase.


Number of Producing Gas Wells and Production per Well
No. of Wells
4000
3500
3000
2500
2000
1500
1000
500
0
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0
Production per Well (1000 cubic metres per day per well)
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
Year
No. of Producing Gas Wells
Production per Gas Well

RESULTS

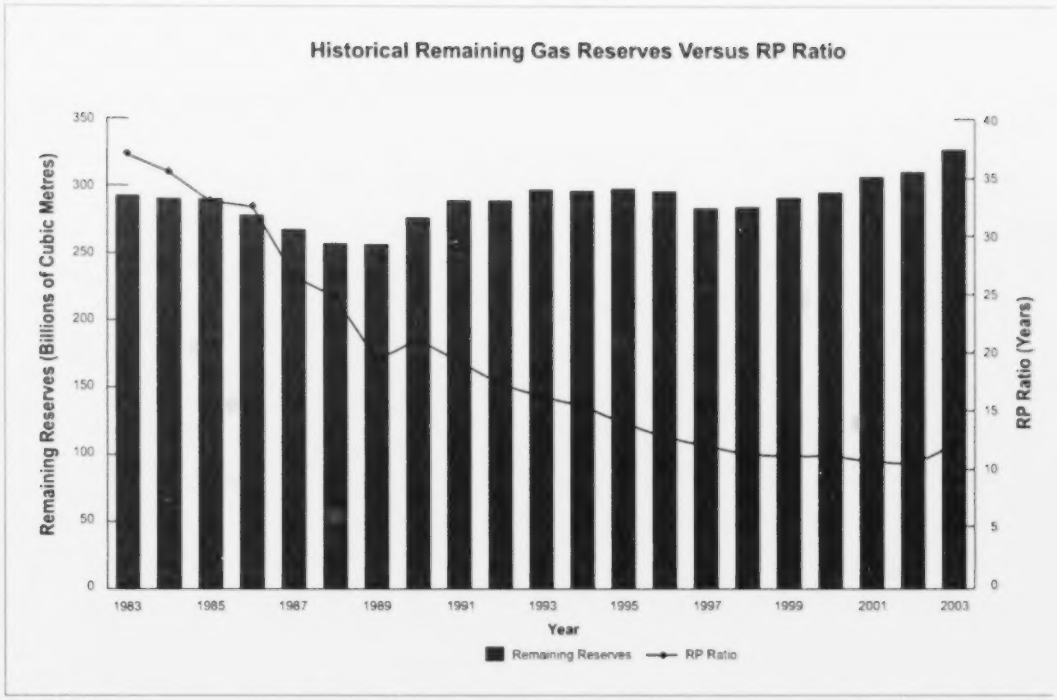
Gas Production and Reserves

The province's established remaining reserves of natural gas were 326.9 10^9m^3, raw, or 259.9 10^9m^3, marketable, as of December 31, 2003. These figures represent the highest level of established gas reserves in the province's history. The 2003 year end raw gas reserves figure represents a 5% increase over the 2002 year-end raw reserves.



Natural gas production for the year, at 30.8 10^9m^3 raw, is a 5% decrease from the preceding year's production. The decrease in the level of production reflects the large decline of productivity of the Ladyfern Slave Point. The decline at Ladyfern was not unexpected and was large enough to more than offset the new production brought on stream as a result of industry's exploration and development efforts throughout the province.

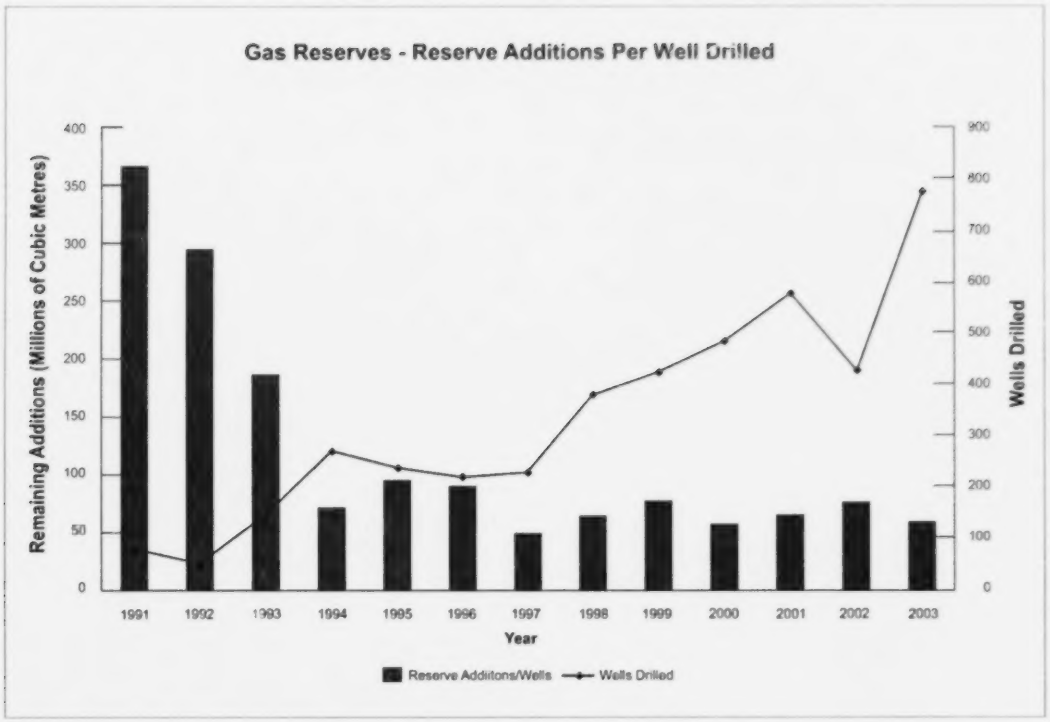
The industry's exploration and development activities in British Columbia replaced 148% of the production. The increase in reserves more than offsets the depletion of Ladyfern. The combination of decreased production and increased reserves suggests a return to more typical reservoir performance for British Columbia. The increase of the reserves to production (R/P) ratio to 10.6, up from 9.6 in 2002, illustrates this return to more established performance.



The largest increases in reserves were realized from industry activity in developing the Jean Marie formation. Activity in the Gunnell Creek Jean Marie A pool led to the booking of an additional 3351 10^6 m^3 of initial reserves. Re-mapping of the Jean Marie A and B pools at Peggo-Pesh and the Jean Marie A at Helmet, resulted in a net increase in initial reserves of 2336 10^6 m^3 for the two fields. With activity continuing at a strong pace to further develop the Jean Marie formation, additional reserve bookings are anticipated.

The deep Devonian activity initiated by Ladyfern continues to yield new reserves. Exploration drilling has resulted in the discovery of a new Slave Point pool at Milligan Creek. In addition to the Slave Point activity chasing the Ladyfern–Cranberry trend, the Slave Point reef front has seen some renewed interest with additional initial reserves of 530 10^6 m^3 being recognized at Clarke Lake. A further 490 10^6 m^3 initial reserves have been booked to the Adsett Member of the Slave Point at Adsett as a result of industry drilling activity.

The Commission has booked an additional 3702 $10^6 m^3$ of initial reserves in the Notikewin formation at Drake and Pickell. The Commission considers the Notikewin to have substantial potential in this region and anticipates continued strong activity in developing the formation's reserves in the Drake, Dahl, Velma, and Pickell areas.



Exploration activity at Monias has resulted in the discovery of a new Halfway pool with initial reserves of 1133 10^6m^3. Performance reviews on a number of Halfway pools plus the identification of several new small Halfway pools have resulted in revisions and bookings to initial reserves totalling approximately 3900 106 m3 in addition to the Monias discovery. The Commission will continue to monitor Halfway performance to determine if further reserve appreciation may be expected.

A total of 1070 10^6m^3 of initial reserves have been booked to newly developed Cadomin pools in the Kelly-Cutbank area. While the currently booked values are not particularly large, the Commission anticipates large bookings in this area in the future. As the industry identifies techniques and practices that will economically develop the extensive gas resource of the Cadomin in the Deep Basin, large reserves are expected to be booked to meet a significant portion of British Columbia's gas market requirements over the immediate to mid-term future.

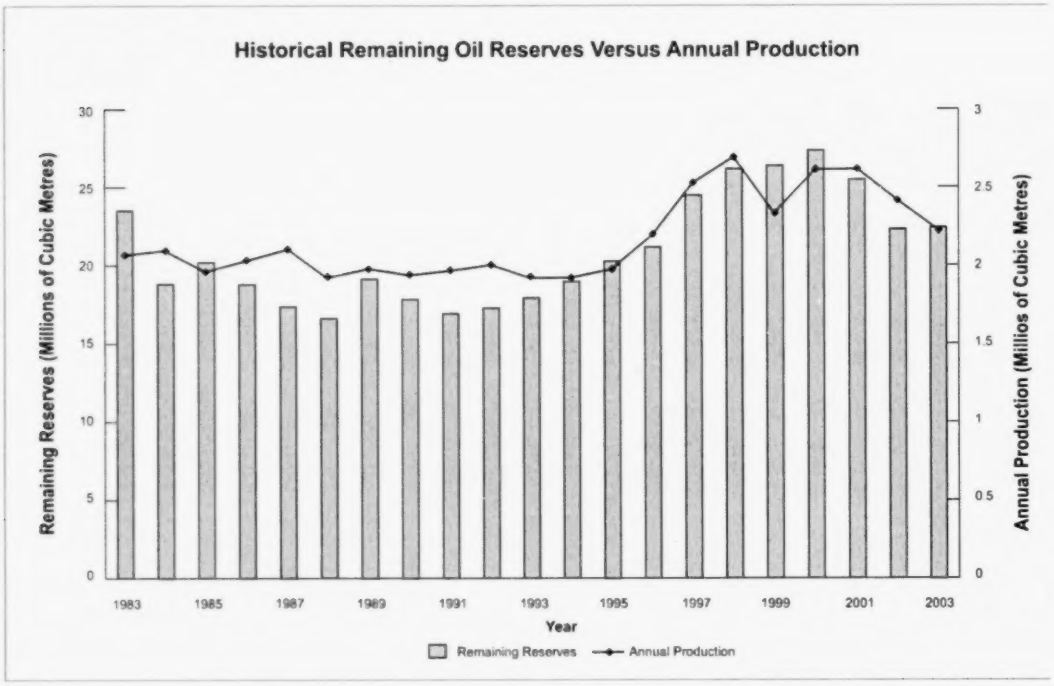
Typical recoverable reserve additions per new well held steady at approximately 60 10^6m^3. The development of plays requiring more than the traditional one vertical well per square mile (e.g., Jean Marie, Cadomin) is expected to see this value decrease in coming years.

Established Raw Gas Reserve Changes

	Change in Reserves (10^9 m^3)
Revisions	**26.3**
Additions from Drilling	**19.3**
Total	**45.6**

Oil Production and Reserves

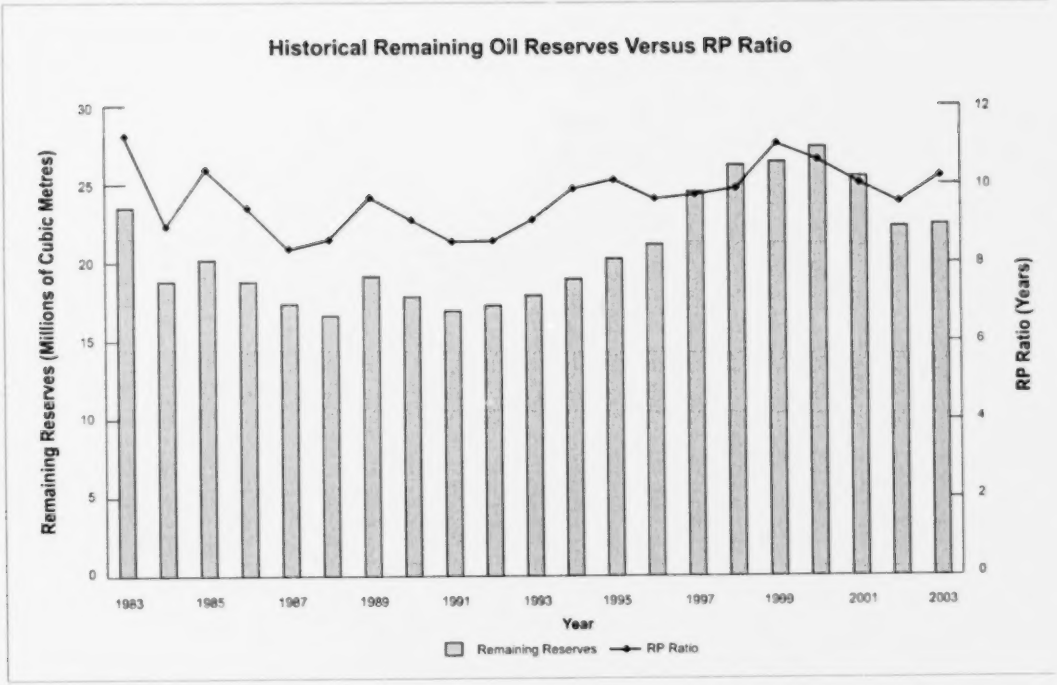
The province's oil production for the 2003 calendar year was 2.2 10^6m^3, slightly less than the production volume for the previous year. Sixty-nine oil wells were drilled during the year, a 73% increase over year 2002. In spite of the increased level of drilling activity, the oil remaining reserves as of December 31, 2003, at 22.4 10^6m^3, showed only a 0.1 10^6m^3, or less than a 1%, increase from the previous year.



The slight decrease of oil production volume and slight increase of reserves have resulted in a remaining reserves to production ratio (R/P ratio) of 10.2, up from 9.4 in year 2002. Reserve additions through drilling and reserve revisions added 2.4 10^6m^3 to the province's initial reserve figures, giving a 110% replacement for the volume produced during the year.

Drilling activity aimed at the discovery of new oil pools, again focused on Triassic sediments in the Fort St. John area, gave reserve bookings of 424 10^3 m^3. The figure virtually matches the previous year's bookings of 427 10^3 m^3. The most significant portion of the reserve additions through drilling is contributed by the Halfway formation, accounting for 203 10^3 m^3 or 48%.

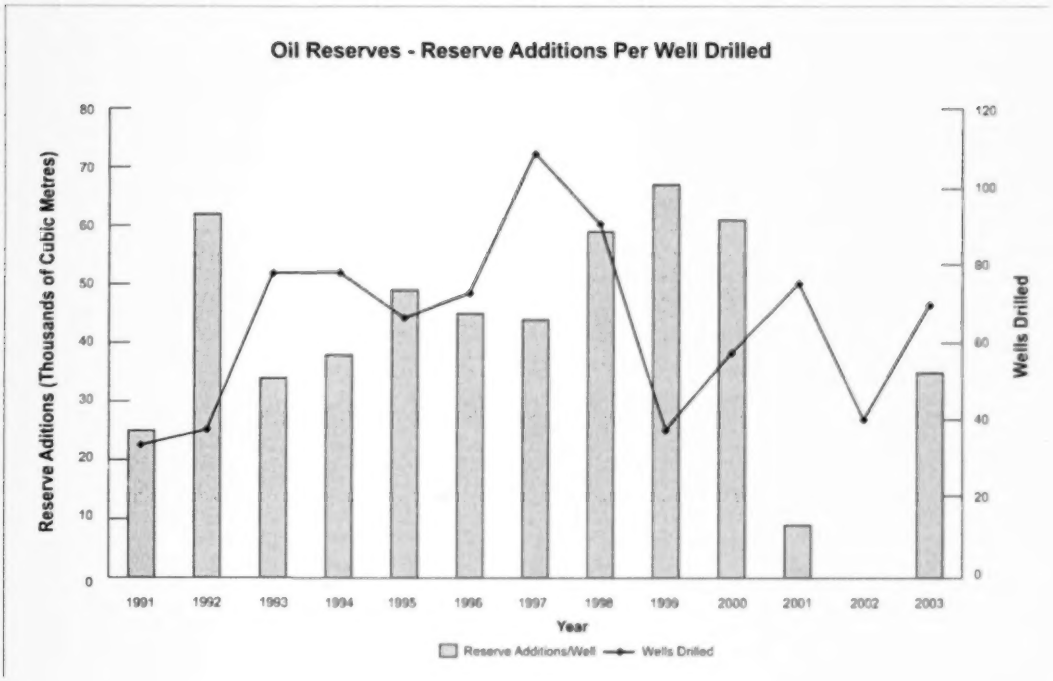
The production performance and continuing development of the Bluesky B pool at Hay River contributed the most significant oil reserve revisions during calendar 2003. The initial reserves for the Nexen project were increased by 818 10^3m^3 and those of the new Husky project were attributed 200 10^3m^3 for a total Hay River Bluesky B initial reserves increase of 1018 10^3m^3. The pool, comprised of the two projects has, as of December 31, 2003, remaining reserves of 1330 10^3m^3, compared to 649 10^3m^3 booked to the pool at year-end 2002. Pool production during 2003 totalled 268 10^3m^3



The next largest single pool reserve revision was booked to the Mica A pool in the Mica field. Based on ongoing strong production performance the initial reserve figure has been increased by 125 10^3m^3 to give remaining reserves of 123 10^3m^3.

Continuing strong performance of waterflood operations at the Rigel Cecil B and Cecil G pools has provided initial reserve increases totalling 224 10^3m^3. Original oil in place volumes have been increased for both pools but the recovery factor for the Cecil B pool has been decreased from 50% to 44%, all on the basis of production performance supported by material balance calculations.

The modest increase in reserve revisions, coupled with slightly reduced production rates, gives reserves added per well drilled of 35 10^3m^3, up considerably from the two most recent past years but still well below typical long term values. As elsewhere in the Western Canadian Sedimentary Basin, the decreasing prize per well drilled may simply be a reflection of the maturity of the British Columbia portion of the basin. The Commission will continue to monitor findings per well and related data.



British Columbia's oil fields continue to be dominated by secondary recovery schemes. Waterflood pools account for approximately 50 % of remaining oil reserves with Boundary Lake continuing to be the dominant contributor. Gas injection is currently occurring in four pools and contributes about 2% to the provincial remaining reserves with the Brassey field accounting for the largest portion.

Established Crude Oil Reserve Changes

	Change in Reserves (10^3 m^3)
Revisions	**424**
Additions from Drilling	**1990**
Total	**2414**

Detailed reserves data by field and pool are contained in the *Hydrocarbon and By-Product Reserves in British Columbia, December 31, 2003* report. The report is available from Crown Publications, 521 Fort Street, Victoria, BC, V8W 1E7, (250) 386-4636, http://crownpub.bc.ca/.

Outlook

Oil and Conventional Natural Gas

Western Canadian Sedimentary Basin

Based on studies conducted by the Geologic Survey of Canada (GSC), the National Energy Board (NEB), and the Ministry of Energy and Mines (MEM), the ultimate potentials for the Western Canadian Sedimentary Basin (WCSB) within British Columbia are recognized as 150 10^6 m^3 of oil and from 1444 10^9m^3 to 1954 10^9m^3 of marketable natural gas. To date 124.6 10^6 m^3 of oil and 711 10^9m^3 of marketable natural gas have been recognized as recoverable reserves. Of these initially recoverable reserves, to date 102.2 10^6 m^3 of oil and 451 10^9m^3 of marketable natural gas have been recovered. The remaining undiscovered potentials for the WCSB within British Columbia, are recognized as 25.4 10^6m^3 of oil and from 734 10^9m^3 to 1243 10^9m^3 of marketable natural gas.

The success of the resource-play approach adopted in pursuit of the gas in the Jean Marie formation in the extreme northeast part of the province appears to be encouraging operators to apply similar approaches in other areas. Most notably development of the Cadomin formation in the Kelly-Cutbank Deep Basin is expected to follow the resource-play approach. Initial efforts now underway are anticipated to identify drilling and completion techniques and practices that will support economic development of the play.

Work by the GSC has also identified significant potential in interior and offshore basins that are, to-date, unexplored. The following table summarizes the potential estimates of the GSC for these basins.

Development of the offshore basins will require concerted effort on the part of the provincial and federal governments to establish an attractive exploratory climate that safeguards the environment and benefits the people of British Columbia. Once such a climate is in place, major financial and resource commitments from industry will be required. As witnessed in the oil and gas developments off the east coast of Canada, large scale projects with long lead times are required to develop such resources.

Hydrocarbon Potential for Frontier Regions

Regions	Gas (10^9m^3)	Oil (10^6m^3)
Bowser Basin and Whitehorse Trough	386	400
Fernie Basin	11	143
Georgia Basin (onshore & offshore areas)	183	
Nechako Basin	268	810
Queen Charlotte Basin (onshore & offshore areas)	730	1560
Tofino and Winona Basins (offshore areas)	265	
Total	1843	2913

Non-Conventional Natural Gas

Coalbed Gas

Although the coalbed gas (CBG) potential of British Columbia appears to be exceptionally large at present none of this potential has been demonstrated to be commercially recoverable. The Commission, therefore, can recognize no CBG reserves.

There has been considerable recent interest by several industry companies in the CBG potential of British Columbia. As of December 31, 2003, the Commission had issued approvals for 11 experimental CBG schemes. The approvals are for schemes proposed in the southeast part of the province as well as in northeast area, the traditional oil and gas area. There is also interest in the CBG potential of Vancouver Island.

Coalbed Methane Potential

Area / Basin	Potential ($10^9 m^3$)
Western Canada Sedimentary Basin in northeastern BC	1690
Bowser and Nechako Basins	255
Fernie Basin	535
Georgia Basin (includes Vancouver Island)	30
Total	2510